3.25 PIPELINE RELIABILITY AND SAFETY

This section relates mostly to the natural gas pipeline component. The transportation of natural gas by pipeline involves some risk to the public in the event of an accident and subsequent release of gas. The greatest hazard is a fire or explosion following a major pipeline rupture. This section explains relevant background to natural gas pipeline safety standards, provides relevant industry incident and safety statistics, relates this proposed project to industry-wide statistics, and assesses relevant mitigating measures.

Methane, the primary component of natural gas, is colorless, odorless, and tasteless. While there are differing opinions regarding methane's relative toxicity, for the purpose of this EIS, methane is considered toxic in keeping with its listing on the EPA's Toxic Substances Control Act inventory and is a simple asphyxiate. If breathed in high concentration, oxygen deficiency can result in serious injury or death. Methane has an autoignition temperature of 1,000°F and is flammable at concentrations between 5 and 15 percent in air. Unconfined mixtures of methane in air are rarely explosive. However, a flammable concentration within an enclosed space in the presence of an ignition source can explode. It is buoyant at atmospheric temperatures and disperses rapidly in air.

SYNOPSIS

This section describes current conditions and evaluates potential impacts to pipeline reliability and safety from the proposed action and alternatives.

Background:

The USDOT is mandated to set pipeline safety standards under Title 49, USC Chapter 601. The USDOT's PHMSA oversees the national regulatory program to ensure the safe transportation of natural gas and other hazardous liquids by pipeline. The USDOT Pipeline Safety Regulations (PSR) are published in 49 CFR Parts 190 to 199.

The pipeline and aboveground facilities associated with the proposed project must be designed, constructed, operated, and maintained in accordance with the Part 192 of the PSR. The regulations prescribe minimum safety requirements for the transportation of natural gas. The transportation of natural gas by pipeline involves some risk to the public in the event of an accident and subsequent release of gas. The greatest hazard is a fire or explosion following a major pipeline rupture. This section explains relevant background to natural gas pipeline safety standards, provides relevant industry incident and safety statistics, relates this proposed project to industry-wide statistics, describes the proposed pipeline design and approach to ensuring pipeline reliability, and assesses relevant mitigating measures.

Expected Effects:

<u>Alternative 1</u>: No Action – Under this alternative, the proposed pipeline would not be constructed. Therefore, there would be no impacts to public health and safety associated with

the risk of a pipeline accident. (PHMSA's NEPA regulations have specific requirements, including for the No Action Alternative, that are addressed in Appendix E.)

Alternative 2: Donlin Gold's Proposed Action - The pipeline and related appurtenances would be designed, constructed and operated in accordance with the applicable requirements of 49 CFR Part 192 for subsurface pipelines. Donlin Gold would incorporate pig launching and receiving facilities (receipt, midpoint, and delivery site), 20 main line valves (MLVs), cathodic protection, leak detection, external coating, and supervisory control into the proposed pipeline system. The tie-in facility, compressor station, Farewell launcher/receiver site, above ground fault crossings, and all MLV sites would be fenced and the gates locked. The pipeline terminus facility would not require fencing because it is located at the secure Donlin Gold mine site. Periodic inspections of the pipeline facilities would be conducted to verify site security.

A 14-inch (356 mm) diameter (outside diameter), American Petroleum Institute specification 5L X-52 PSL2 pipe would be used. The pipe would have a baseline wall thickness (WT) of 0.312 inches (7.9 mm), a yield strength of 52,000 pounds per square inch (psi), and a maximum allowable operating pressure (MAOP) of 1,480 psi gauge. If a subsequent increase in population density adjacent to the right-of-way (ROW) indicates a change in class location for the pipeline, Donlin Gold would have to reduce the MAOP or replace the segment with pipe of sufficient grade and wall thickness, if required, to comply with the USDOT code of regulations for the new class location.

While a WT of 0.312 inches (7.9 mm) would comply with the requirements for the designated line class, additional WT would be required in areas where geotechnical hazards are present unless a system-specific Special Permit was granted by PHMSA. Geotechnical hazards include areas prone to thaw settlement, frost heave and fault zones and pipe in these areas would require a WT of 0.344 inches (8.7 mm) or 0.375 inches (9.5 mm). Similarly, a greater WT (0.375 inches) would be required for pipe that would be laid in areas requiring additional strength during pressure testing because of large elevation changes or requiring buoyancy control in wetlands. (Section 2.3.2.3.5, Alternatives, describes the design and construction procedures that would be used at wetland crossings, and impacts to wetlands hydrology resulting from pipeline construction are discussed in detail in Section 3.11.4.2.3, Wetlands.) Finally, for horizontal directional drilling (HDD) installations, above ground fault crossings, and other high hazard areas, a 0.406-inch (10.3 mm) WT is specified.

If the proposed pipeline does not comply with the above described WT requirements, Donlin Gold will apply to PHMSA for a Special Permit under 49 CFR 190.341 for construction of the proposed pipeline due to the use of strain-based design in areas of discontinuous permafrost. If PHMSA elects to grant the Special Permit for the project, the permit would contain conditions specific to the design, construction, and operation and maintenance of the pipeline as well as reporting and certification requirements. These conditions are summarized in this section to demonstrate that, for the purposes of this EIS, any difference in terms of pipeline integrity, potential releases or environmental consequences between operation under a special permit or standard design would be minimal, because the PHMSA Special Permit approval is conditioned on achieving equal or greater factors of safety than the general design criteria (PHMSA 2013d briefing of Cooperating Agencies). If the Special Permit application complies with 49 CFR 190.341 and PHMSA determines that waiver of the regulation(s) are not inconsistent with pipeline safety, PHMSA may grant the permit with any conditions necessary to assure safety, environmental protection, or otherwise in the public interest. Additional details can be found in Appendix E which includes the draft Strain Based Design Special Permit Conditions and the draft Enclosure B which augments this Draft EIS with information to meet PHMSA NEPA requirements for the Special Permit.

According to 49 CFR 192.317: "The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads." As described in Section 3.25.1, while a WT of 0.312 inches (7.9 mm) would comply with the requirements for the designated line class, the pipeline would be designed with additional WT in areas where geotechnical hazards are present. In addition, the pipeline would be designed to withstand the stress that could occur during a seismic event. Two active faults, the Castle Mountain Fault and the Denali Fault, cross the proposed pipeline route (Wesson et al., 2007). Large, permanent ground movement at the pipeline crossing and strong ground shaking along the pipeline could occur during a seismic event on either fault. As described in Section 8.6.18 of the Natural Gas Pipeline Plan of Development (POD), a preliminary fault-crossing stress analysis conducted for both crossings produced a recommendation for an above grade design with the pipeline in a "Z" configuration at each end of the potential movement zone to ensure flexibility. Final designs for the aboveground crossings at the Denali-Farewell and Castle Mountain Faults would be developed to allow the pipe to move freely on above ground support beams during seismic shifting of the ground at these crossings without overstressing the pipe.

<u>Other Alternatives</u>: The effects of other alternatives on pipeline reliability and safety would be very similar to the effects of Alternative 2. Differences of note include:

- *Alternative 6A (Dalzell Gorge Route)* – The pipeline route would be the same for Alternative 6A as for Alternative 2, with the exception of a different alignment between MP 106.5 and MP 152.7.

3.25.1 SAFETY STANDARDS

The USDOT is mandated to provide pipeline safety under Title 49, USC Chapter 601. The USDOT's PHMSA oversees the national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. It develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards which set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve safety. The PHMSA ensures that people and the environment are adequately protected from the risk of pipeline incidents. This work is shared with state agency partners and others at the federal, state, and local level. The Natural Gas Pipeline Safety Act at 49 U.S.C. 60105 provides for a state agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing the federal standards, while 49 U.S.C. 60106 permits a state agency that does not qualify under 49 U.S.C. 60105 to perform certain inspection and monitoring functions. A state may also act as the USDOT's agent to inspect interstate facilities within its boundaries; however, the USDOT is responsible for enforcement actions. The majority of the states have either certifications or agreements with USDOT under the Natural Gas Pipeline Safety Act, while nine states act as interstate agents.

The State of Alaska does not have either a certification or an agreement with USDOT under the Natural Gas Pipeline Safety Act. If the State of Alaska elects to issue a ROW lease and BLM elects to issue a ROW grant to Donlin Gold for the proposed pipeline, those agreements would contain a comprehensive sequence of stipulations that would direct all aspects of the pipeline design, construction, and operation in conjunction with applicable PHMSA regulations.

The USDOT pipeline standards are published in 49 CFR Parts 190 to 199. Parts 190, 191, 192, and 199 apply to the proposed pipeline, and natural gas pipeline safety issues are specifically addressed in 49 CFR Part 192. The pipeline and aboveground facilities associated with the proposed project must be designed, constructed, operated, and maintained in accordance with the USDOT Minimum Federal Safety Standards in 49 CFR Part 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility incidents and failures. Part 192 of 49 CFR prescribes minimum requirements for: the selection and qualification of pipe and components; design of pipe; design and installation of pipeline components and facilities; welding; constructing; and protection from external, internal, and atmospheric corrosion; the minimum leak-test and strength-test requirements for pipelines; minimum requirements for operation; minimum requirements for maintenance; minimum requirements for operator qualification; and minimum requirements for an integrity management program.

Area classifications based on population density in the vicinity of the pipeline are also defined by 49 CFR Part 192, which also specifies more rigorous safety requirements for populated areas. The class location unit is an area that extends 220 yards (660 feet) on either side of the centerline of any continuous 1 mile length of pipeline. The four area classifications are defined as follows:

- Class 1 – Location with 10 or fewer buildings intended for human occupancy;
- Class 2 – Location with more than 10 but less than 46 buildings intended for human occupancy;
- Class 3 – Location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of any building, or small well-defined outside area occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12-month period; and
- Class 4 – Location where buildings with four or more stories aboveground are prevalent.

Class locations representing more populated areas require higher safety factors in pipeline design, testing, and operation. Pipelines constructed on land in Class 1 locations must be installed with a minimum depth cover of 30 inches in normal soil and 18 inches in consolidated rock. Class 2, 3, and 4 locations, as well as drainage ditches of public roads and railroad crossings, require a minimum cover of 36 inches in normal soil and 24 inches in consolidated rock. All pipelines installed in navigable rivers, streams, and harbors must have a minimum cover of 48 inches in soil and 24 inches in consolidated rock. The rivers and streams that the proposed pipeline would cross, as well as the bankfull width of these crossings (where data are available), are listed in Table 3, Appendix G.

Class locations also specify the maximum distance to a sectionalizing block valve. Pipe wall thickness and pipeline design pressures, hydrostatic test pressures, MAOP, inspection and testing of welds and frequency of pipeline patrols and leak surveys must also conform to higher standards in more populated areas. The preliminary class location for the proposed pipeline has been determined based on the relationship of the pipeline centerline to other nearby structures and manmade features. The entire proposed pipeline route is currently designated as Class 1 (Enos 2013e).

Donlin Gold anticipates the need for a special permit. As discussed in their December 2013 Plan of Development under Pipeline Design Factors: "In areas where the pipeline may cross terrain susceptible to thaw settlement or other geotechnical conditions that subject the pipeline to additional strain, a special permit may be required from PHMSA. In these areas the conditions of the special permit will be the guiding requirements for the design, construction, and operation of the pipeline." The Lead and Cooperating Agencies were briefed on November 11, 2013 by PHMSA representatives regarding their role, the special permit process, strain-based design and requirements therefore. The notes of this meeting and PHMSA Power Point presentation are documented in the Administrative Record for this EIS. The Special Permit Conditions and Enclosure B prepared by Donlin Gold are presented in Appendix E to this EIS.	PHMSA Special Permits or Strain-Based Design Any special permits granted based upon strain-based design will be supported by pipeline engineering evaluations sufficient to warrant PHSMA approval. Discussion of the engineering principles underlying PHMSA's consideration of a special permit based upon strain-based design is complicated but a July 30, 2013 article published on Arcticgas.gov by the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects provides useful background. This article is available at http://www.arcticgas.gov/buried-alaska-gas-line-could-face-powerful-bending-forces

The Pipeline Safety Improvement Act of 2002 requires operators to develop and follow a written integrity management program that contains all the elements described in 49 CFR 192.911 and addresses the risks on each transmission pipeline segment. Specifically, the law establishes an integrity management program which applies to all high consequence areas (HCAs). The integrity management program is an additional layer of regulatory requirements beyond the operations, maintenance, and other 49 CFR Part 192 requirements for pipelines in HCAs.

The USDOT has published rules that define HCAs as locations where a gas pipeline accident could do considerable harm to people and their property and requires an integrity management program to minimize the potential for an accident. This definition satisfies, in part, the Congressional mandate for the USDOT to prescribe standards that establish criteria for identifying each gas pipeline facility in a high density population area.

The HCAs may be classified in one of two ways. In the first method, an HCA includes:

- Current Class 3 and 4 locations;
- Any area in Class 1 or 2 where the potential impact radius[1] is greater than 660 feet and there are 20 or more buildings intended for human occupancy within the potential impact circle[2]; or
- Any area in Class 1 or 2 where the potential impact circle includes an identified site.

An identified site is an outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12-month period; a building that is occupied by 20 or more persons on at least 5 days a week for any 10 weeks in any 12-month period; or a facility that is occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate.

In the second method, an HCA includes any area within a potential impact circle which contains:

- Twenty or more buildings intended for human occupancy; or
- An identified site.

Once a pipeline operator has determined the HCAs along its pipeline, it must apply the elements of its integrity management program to those segments of the pipeline within HCAs. USDOT regulations specify the requirements for the integrity management plan at 49 CFR 192.911.

Donlin Gold has not identified any HCAs along the proposed project route based on the relationship of the pipeline centerline to other nearby structures and identified sites. To maintain compliance with the pipeline classification and pipeline integrity management regulations in 49 CFR Part 192, Donlin Gold would continue to monitor for potential class location changes and HCAs throughout the life of the proposed project. Monitoring would include visual inspections of the pipeline ROW and surrounding area, regular updates to the project's GIS data, and monitoring for changes to land status (Enos 2013e). Should any HCAs along the proposed project route be identified in the future, the pipeline integrity management rule would require inspection of the HCA segments of the pipeline every 7 years. As further required by the pipeline integrity management rule, inspections of the above ground portions of the pipeline would be required at least once every 3 calendar years (with intervals not to exceed 39 months) regardless of class location. The USDOT prescribes the minimum standards for operating and maintaining pipeline facilities, including the requirement to establish a written plan governing these activities. Each pipeline operator is required to establish an emergency plan that includes procedures to minimize the hazards in a natural gas pipeline emergency. Key elements of the plan include procedures for:

1 The potential impact radius (in feet) is calculated as the product of 0.69 and the square root of the MAOP of the pipeline in pounds per square inch gauge (psig) multiplied by the square of the pipeline diameter in inches.

2 The potential impact circle is a circle of radius equal to the potential impact radius.

- Receiving, identifying, and classifying emergency events, gas leakage, fires, explosions, and natural disasters;
- Establishing and maintaining communications with local fire, police, and public officials and coordinating emergency response;
- Emergency system shutdown and safe restoration of service;
- Making personnel, equipment, tools, and materials available at the scene of an emergency; and
- Protecting people first and then property and making them safe from actual or potential hazards.

The USDOT requires that each operator establish and maintain liaison with appropriate fire, police, and public officials to learn the resources and responsibilities of each organization that may respond to a natural gas pipeline emergency and to coordinate mutual assistance.

In accordance with 49 CFR Part 192, Donlin Gold would develop an O&M Plan / Manual; Health, Safety, and Environment Plan (including a Safety Plan / Program), Pipeline Surveillance and Monitoring Plan, and other plans that would outline safety measures that would be implemented during normal and abnormal operation. In order to meet ADNR's ROW lease requirements, Donlin Gold would maintain a surveillance and monitoring program as well as a quality assurance program. Donlin Gold would conduct a public outreach program that would include information regarding participation in the "One-Call" program, hazards associated with the unintended release of natural gas, unintended release indicators, and reporting procedures.

3.25.2 PIPELINE ACCIDENT DATA

The USDOT requires all operators of natural gas transmission pipelines to notify the USDOT of any significant incident and to submit a report within 20 days. Significant incidents are defined as any leaks that:

- Caused a death or personal injury requiring hospitalization;
- Involve property damage of more than $50,000, in 1984 dollars[3];
- Result in highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more; or
- Result in liquid releases resulting in an unintentional fire or explosion.

During the 20-year period from 1993 through 2012, a total of 1,211 significant incidents were reported to PHMSA on the more than 300,000 total miles of natural gas transmission pipelines nationwide (PHMSA 2013a). Additional insight into the nature of significant incidents may be found by examining the primary factors that caused the failures. Table 3.25-1 provides a distribution of the causal factors as well as the number of each incident by cause.

3 $50,000 in 1984 dollars was approximately $112,549 as of August 2013 (U.S. Department of Labor 2013).

Table 3.25-1: Natural Gas Transmission Pipeline Significant Incidents by Cause 1993-2012

Cause	Number of Incidents	Percentage
Corrosion	287	23.7%
Excavation Damage[1]	202	16.6%
Incorrect Operation	32	2.6%
Pipeline Material, Weld or Equipment Failure	285	23.5%
Natural Force Damage	144	11.8%
Other Outside Force Damage[2]	67	5.5%
All Other Causes[3]	194	16.0%
Total:	1,211	100%

Notes:

1 Includes third-party damage.
2 Fire, explosion, vehicle damage, previous damage, intentional damage.
3 Miscellaneous causes or unknown causes.

Source: PHMSA 2013a.

The dominant incident cause is corrosion, which constitutes 23.7 percent of all significant incidents. The pipelines included in the data set in Table 3.25-1 vary widely in terms of age, pipe diameter, and level of corrosion control. Each variable influences the incident frequency that may be expected for a specific segment of pipeline.

The frequency of significant incidents is strongly dependent on pipeline age. Older pipelines have a higher frequency of corrosion incidents, since corrosion is a time-dependent process. The use of both an external protective coating and a cathodic protection system[4], required on all pipelines installed after July 1971, significantly reduces the corrosion rate compared to unprotected or partially protected pipe. The proposed pipeline would include an external protective coating and a cathodic protection system, thereby reducing the risk of a corrosion incident.

Outside forces, excavation, or natural force damage is the cause in 33.9 percent of significant pipeline incidents (see Table 3.25-1). These result from the encroachment of mechanical equipment such as bulldozers and backhoes; earth movements due to soil settlement, washouts, or geologic hazards; and weather effects such as winds, heavy rains/floods, and thermal strains (Table 3.25-2).

Table 3.25-2: Outside Force, Excavation, and Natural Force Incidents by Cause, 1993-2012

Cause	Number of Incidents	Percent of all Outside Force, Excavation, and Natural Force Incidents
Other Outside Force Damage		
Fire/Explosion as Primary Cause	8	1.9%
Vehicle (not engaged in excavation)	42	10.2%

[4] Cathodic protection is a technique to reduce corrosion of the natural gas pipeline that includes the use of an induced current or a sacrificial anode (like zinc) that corrodes at faster rate. A description of corrosion protection and detection systems proposed to be employed for the proposed pipeline can be found in Section 2.3.2.3.5.

Table 3.25-2: Outside Force, Excavation, and Natural Force Incidents by Cause, 1993-2012

Cause	Number of Incidents	Percent of all Outside Force, Excavation, and Natural Force Incidents
Fishing, Maritime Activity, Maritime Equipment, or Vessel Adrift	6	1.5%
Previous Mechanical Damage	5	1.2%
Intentional Damage	1	0.2%
Other or Unspecified Outside Force Damage	5	1.2%
Subtotal	**67**	**16.2%**
Excavation		
Operator/Contractor Excavation Damage	25	6.1%
Third-party Excavation Damage	169	40.1%
Previous Damage due to Excavation	4	1.0%
Unspecified Excavation Damage	4	1.0%
Subtotal	**202**	**48.9%**
Natural Force Damage		
Earth Movement	38	9.2%
Heavy Rains/Floods	70	16.9%
Lightning/Temperature/High Winds	21	5.1%
Other or Unspecified Natural Force Damage	15	3.6%
Subtotal	**144**	**34.9%**
Total	***413***	***100%***

Source: PHMSA 2013a

Older pipelines have a higher frequency of outside forces and excavation incidents partly because their location may be less well known and less well marked than newer lines. In addition, older pipelines include a disproportionate number of smaller diameter pipelines, which have a greater rate of outside forces incidents. Smaller diameter pipelines (e.g., local distribution lines) are more easily crushed or broken by mechanical equipment or earth movements than larger diameter pipelines. The remote nature of the pipeline route and extremely low adjacent population lessens the possibility of outside force damage or inadvertent third-party damage through excavation. Natural force damage caused by earth movement is a greater concern given the potential for fault displacement to occur in some areas along the pipeline route. Section 3.25.3.2.2 describes how the proposed pipeline would be designed to withstand the stress that could occur during a seismic event.

Since 1982, operators have been required to participate in “One Call” public utility programs in populated areas to minimize unauthorized excavation activities in the vicinity of pipelines. The “One Call” program is a service used by public utilities and some private sector companies (e.g., oil pipelines and cable television) to provide preconstruction information to contractors or other maintenance workers on the underground location of pipes, cables, and culverts.

Pipeline material, weld, or equipment failure accounted for 23.5 percent of significant incidents involving natural gas transmission pipelines from the period of 1993 through 2012 (Table 3.25-1). While manufacturing-related pipeline failure was the cause for only 12 out of a total of 285 incidences of pipeline material, weld, or equipment failure, the greatest amounts of property damage (58.5 percent), fatalities (100 percent), and injuries (71.8 percent) in this category were attributable to manufacturing-related pipeline failure. Manufacturing-related pipeline failure includes material defects (e.g., impurities in the molten steel) that arise during manufacturing, and welding that results in cracks, pinholes, or incomplete fusion between the weld and the base metal (PHMSA 2011b). Donlin Gold would observe and comply with PHMSA regulations pursuant to 49 CFR Part 192 that provide stringent standards for pipe materials, pipe design, pipe components, pipe welds, pipeline construction, corrosion protection, pipeline pressure testing, and operation and maintenance.

Since this EIS analyzes a new pipeline in compliance with current standards, the probability and severity of incidents should compare favorably to and not likely exceed industry experience.

3.25.3 IMPACT ON PUBLIC SAFETY

The analysis contained in this section does not readily fit the criteria/impact methods used in other sections of the EIS. As a result, tables of impact criteria and summaries of impacts are not presented.

3.25.3.1 ALTERNATIVE 1 – NO ACTION

Under the No Action Alternative, the proposed pipeline would not be constructed. Therefore, there would be no impacts to public health and safety associated with the risk of a pipeline accident.

3.25.3.2 ALTERNATIVE 2 – DONLIN GOLD'S PROPOSED ACTION

The significant incident data summarized in Table 3.25-1 include pipeline failures of all magnitudes with widely varying consequences.

Table 3.25-3 presents the average annual fatalities that occurred on natural gas transmission lines over a 20-year period (1993-2012) and over a 5-year period (2008-2012). Annual fatalities for the period of 1993-2012 averaged two fatalities. Annual fatalities over the period of 2008-2012 likewise averaged two fatalities.

Table 3.25-3: Annual Average Fatalities – Natural Gas Transmission Pipelines

Period	Fatalities
1993-2012	2
2008-2012	2

Source: PHMSA 2013a and 2013b.

During the period of 2008-2012, 10 fatalities associated with natural gas transmission lines occurred. The majority (80 percent) were caused by the 2010 explosion of a Pacific Gas & Electric (PG&E) 30-inch natural gas transmission line in San Bruno, California. The NTSB determined that the probable cause of the accident included inadequate quality assurance and quality control during installation of a substandard welded pipe section and an inadequate pipeline integrity management program (NTSB 2011).

The nationwide totals of accidental fatalities from various manmade and natural hazards are listed in Table 3.25-4 in order to provide a relative measure of the industry-wide safety of natural gas transmission pipelines. The data shown are from the year 2007, the most recent year for which the applicable data are available from the U.S. Census Bureau. Direct comparisons between accident categories should be made cautiously, however, because individual exposures to hazards are not uniform among all categories. As shown in the table, the fatality rate from natural gas pipelines is more than 22 times lower than the fatalities from natural hazards such as lightning, tornados, or floods.

From 1993 to 2012, there were an average of 61 significant incidents and two fatalities per year (PHMSA 2013a). The number of significant incidents over the more than 300,000 miles of natural gas transmission lines indicates the risk is low for an incident at any given location. This is particularly the case in the proposed Project Area, due to newer technology, regulatory requirements, and the remoteness of the proposed project. The operation of the proposed pipeline would represent only a slight increase in risk to the nearby public. In addition, the proposed pipeline would be constructed in very remote locations and away from HCAs, further minimizing risk to the public. No risk factors were identified that would support public safety risks higher than current industry experience in terms of anticipated number of severity of incidents. The highly remote location of the pipeline could suggest that the risk to human health is lower than other pipelines.

Table 3.25-4: Nationwide Accidental Deaths (2007)

Type of Accident	Number of Deaths
All Accidents	123,706
Motor Vehicle	43,945
Poisoning	29,846
Falls	22,631
Drowning	3,443
Fire, Smoke Inhalation, Burns	3,286
Floods[1]	87
Lightning[1]	45
Tornado[1]	81
Natural Gas Transmission Pipelines[2]	2

Notes:

1 National Marine and Atmospheric Administration (NOAA) 2007.
2 PHMSA 2013c.

Source: U.S. Census Bureau 2012 (unless otherwise noted).

3.25.3.2.1 TERRORISM AND SECURITY ISSUES

Following the terrorist attacks of September 11, 2001, terrorism has become a safety and security concern for energy facilities and is an important consideration for the design, construction, and operation of energy facilities. Both international and domestic terrorism have changed the way pipeline operators as well as regulators must consider pipeline security, both in approving new projects and in operating existing facilities. The likelihood of future attacks of terrorism or sabotage occurring along the proposed project is extremely difficult to estimate, but is expected to be unlikely due to the remoteness of the site, the relative absence of opportunities for collateral or significant environmental damage, and that a break would not impede infrastructure relied upon for national defense or everyday life. However, intentional damage to the pipeline still has the potential to occur.

Design, construction, and operations elements already integrated into the proposed project provide a level of security from such a threat including buried construction of the pipeline; locked security fencing surrounding aboveground facilities; and periodic air and ground inspection of the pipeline route. Additionally, specialized training in pipeline security awareness for pipeline employees is recommended by the Transportation Security Administration (Transportation Security Administration 2011) and will be described in operating manuals prepared prior to operation. Further, specific information including pipeline design and integrity; security risks; and HCAs are frequently kept confidential from the public in order to maintain a higher level of security.

3.25.3.2.2 PROPOSED PIPELINE DESIGN AND APPROACH TO ENSURING PIPELINE RELIABILITY

Donlin Gold would incorporate pig launching and receiving facilities (receipt, midpoint, and delivery site), 20 main line valves (MLVs) (three of which could be operated remotely), cathodic protection, leak detection, and supervisory control into the proposed pipeline system. The pipeline and related appurtenances would be designed, constructed and operated in accordance with the applicable requirements of 49 CFR Part 192 for subsurface pipelines. The proposed pipeline route was selected following an alternatives screening process, as described in Section 2.2.1, Alternatives. The methods that would be used for wetlands and water body crossings are described in Section 2.3.2.3.5, Pipeline Specifications, in Chapter 2, Alternatives.

A 14-inch (356 mm) diameter (outside diameter), American Petroleum Institute specification 5L X-52 PSL2 pipe would be used. The pipe would have a baseline WT of 0.312 inches (7.9 mm), a yield strength of 52,000 psi, and a MAOP of 1,480 psi gauge. If a subsequent increase in population density adjacent to the ROW indicates a change in class location for the pipeline, Donlin Gold would have to reduce the MAOP or replace the segment with pipe of sufficient grade and wall thickness, if required, to comply with the USDOT code of regulations for the new class location.

While a WT of 0.312 inches (7.9 mm) would comply with the requirements for the designated line class, additional WT would be required in areas where geotechnical hazards are present unless a system-specific special permit was granted by PHMSA. Geotechnical hazards include areas prone to thaw settlement, frost heave, and fault zones, and pipe in these areas would require a WT of 0.344 inches (8.7 mm) or 0.375 inches (9.5 mm). Similarly, a greater WT (0.375 inches) would be required for pipe that would be laid in areas requiring additional strength during pressure testing because of large elevation changes or requiring buoyancy control in wetlands. Finally, for HDD installations, above ground fault crossings, and other high hazard areas, a 0.406-inch (10.3 mm) WT is specified.

Quality Control

Donlin Gold would adhere to its Operations Integrity Management System safeguards and stipulations. To facilitate compliance with the safeguards and stipulations of the ROW authorizations, all contractors would be pre-qualified to verify that they have an Integrity Management System or equivalent in place. In addition, Donlin Gold would implement a Quality Management Program that would:

- Apply to and remain in effect during construction, operation, maintenance and termination;
- Identify the processes needed to be undertaken and the methodologies followed for effective processes;
- Verify resources are dedicated to support the operation and monitoring of the processes; and
- Monitor, measure, and analyze processes and implement corrective actions to processes if necessary.

The Quality Management Program would include a Quality Manual and Quality Control Plan including policies and objectives. Donlin Gold, including its agents, employees, and contractors would comply with the approved Quality Management Program. This program would serve to identify any potential issues and verify that all work is performed in a manner to maintain the quality of the pipeline and related facilities, and to make sure all work is performed in accordance with relevant permit and lease stipulations.

Pipeline Materials and Procedures Control

Materials that would be used in construction of the pipeline would meet the requirements of American Petroleum Institute 5L grade X-52. The material specifications for the pipe are contained in the SBD Special Permit Conditions file in Appendix E. Appropriate quality control would be required of all pipeline material suppliers. Field welds on the pipeline would be inspected using nondestructive testing during construction. Inspectors would be employed to verify compliance with the approved welding procedures and conformance to other construction practices, standards, and requirements.

Pipeline Design in Areas Prone to Fault Displacement

According to 49 CFR 192.317: “The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.” The pipeline would be designed to withstand the stress that could occur during a seismic event. Two active faults, the Castle Mountain Fault and the Denali Fault, cross the proposed pipeline route (Wesson et al., 2007). Large, permanent ground movement at the pipeline crossing and strong ground shaking along the pipeline could occur during a seismic event on either fault. As described in Section 8.6.18 of the Natural Gas Pipeline POD, a preliminary fault-crossing stress analysis conducted for both crossings produced a recommendation for an above grade design with the pipeline in a “Z” configuration at each end of the potential movement zone to ensure flexibility. Final designs for the above-ground crossings at the Denali-Farewell and Castle Mountain Faults would be developed to allow the pipe to move freely on above-ground support beams during seismic shifting of the ground at these crossings without overstressing the pipe.

Welding and Weld Examination

Sections of 60-foot pipe would be delivered in straight sections. The straight sections of pipe would be temporarily placed or “strung” along the excavated pipeline trench, where they would be bent as necessary to follow the natural grade and direction changes of the ROW. Stringing operations would be coordinated with all other installation activities to ensure that the pipe is available for bending, welding, and lowering-in to minimize the amount of time the trench is open. Following stringing and bending, the ends of the pipeline would be carefully aligned and girth-welded together.

All welds would be visually inspected by an American Welding Society certified inspector who is part of the construction management staff or execution contractor quality control staff. Non-destructive radiographic or ultrasonic inspection methods would be used, in accordance with USDOT requirements. The percentage of welds that are inspected would comply with requirements of 49 CFR 192.243, Welds: Nondestructive Testing. Any defects would be repaired or cut out as required under the specified regulations and standards. Documents that verify the integrity of the pipeline would be kept on file by Donlin Gold for inspection by the USDOT Office of Pipeline Safety.

Pressure Testing

The entire pipeline would be pressure tested before it is put into service to verify its integrity and its ability to withstand maximum operating pressures. The test would be conducted in compliance with USDOT regulations (49 CFR Part 192). Before the pressure test, each section of pipe would be cleaned. A detailed Pressure Test Plan would be developed during final design to address all aspects of pressure testing. Donlin Gold has not yet determined whether the pipeline would be pressure tested using water (hydrostatic testing or hydrotesting). Incremental segments of pipe would be filled with water, pressurized, and held for the required duration of the test. The length of each segment tested would depend on topography. Section 2.3.2.3.5, in Chapter 2, Alternatives, contains more information about how the proposed pipeline would be pressure tested.

Cathodic Protection and Corrosion Control

To prevent corrosion, the majority of the pipe would be externally coated with a three-layer polyethylene coating before delivery. The pipe intended for HDD installation would use a fusion bonded epoxy corrosion-prevention coating, finished with an abrasion resistant overlay coating. After welding, field joints would be coated with a shrinkable sleeve wrap, or field-applied liquid epoxy. Before the pipe is lowered into the trench, (or pulled back into an HDD) the coating would be visually inspected and tested with an electronic detector for coating defects. Any defects or scratches (holidays) would be repaired and re-inspected before the pipe is lowered into the trench.

In addition to the pipe coating, a current-passive, zinc ribbon cathodic protection system would be used for the length of the pipeline. Zinc ribbon would be installed after pipe lowering-in and before backfill. Following commissioning and startup of the proposed pipeline, the pipeline would be surveyed at least once each calendar year, but at intervals not exceeding 15 months, to determine whether cathodic protection levels are adequate. Cathodic protection test sites would be installed at accessible locations, at intervals of one mile or less, to measure pipe-to-soil potential for the establishment and maintenance of an effective cathodic protection system. Accessibility would be based on the expected cathodic protection survey season. Test stations would be installed where the pipeline parallels, crosses, or passes near other cathodically protected pipelines or structures. The pipeline would be electrically isolated from contact with the compressor station and at the BPL tie-in. The specific location of test stations would be determined during final design. If low pipe-to-soil potentials are found during cathodic protection surveys, remedial measures would be implemented.

Standard Lowering-In

Before the pipe section is lowered into the trench, inspection would be conducted to verify that the trench bottom is free of rocks and other debris that could damage the external pipe coating. Dewatering may be necessary where water has accumulated in the trench. This would occur in accordance with permit requirements. Sideboom tractors would be used to lift the pipe, position it over the trench, and lower it into place. Specialized padding (soil screening equipment) machines may be used to screen previously excavated mineral soils to provide a padding and bedding material free of larger material (>1 inch in size) to line the bottom of the trench before lowering-in pipe, and to provide backfill material next to the sides and the top of the pipe that would not damage the pipe coating. The pipeline coating would be inspected again just before the pipe is placed in the trench.

Operations and Maintenance Inspections

When the pipeline is in operation, the pipeline would be periodically inspected using intelligent inspection pigs, which are in-line inspection (ILI) tools. The O&M Plan/Manual and Pipeline Surveillance and Monitoring Plan would provide details about inspection pigging, and would define the types and frequency of inspection pigs to be run through the pipeline. The first inspection pig run would establish baseline pipeline conditions. Subsequent pig runs would be scheduled to monitor and detect changes from the baseline conditions. The need for and frequency of the pig runs would be evaluated based on results from previous pig runs and on operating experience and requirements.

3.25.3.2.3 IMPACTS OF A SPECIAL PERMIT FOR STRAIN-BASED DESIGN

If the proposed pipeline does not comply with the above described WT requirements, Donlin Gold will likely apply to PHMSA for a Special Permit under 49 CFR 190.341 for construction of the proposed pipeline due to the use of strain-based design in areas of discontinuous permafrost. If PHMSA elects to grant the Special Permit for the project, the permit would contain conditions specific to the design, construction, and operation and maintenance of the pipeline as well as reporting and certification requirements. These conditions are summarized herein to demonstrate that, for the purposes of this EIS, any difference in terms of pipeline integrity, potential releases or environmental consequences between operation under a special permit or standard design would be minimal, because the PHMSA Special Permit approval is conditioned on achieving equal or greater factors of safety than the general design criteria (PHMSA 2013d). Additional details can be found in the Donlin Gold LLC Application for Special Permit (Enclosure B) and the SBD Special Permit Conditions file contained in Appendix E.

The SBD Special Permit Conditions specify that Donlin Gold must develop and submit to PHMSA for review an overall SBD Plan that addresses all aspects of the pipeline's life cycle including design, materials, construction, and operations and maintenance. The SBD Plan must be reviewed and validated by a third-party engineering firm. In addition, Donlin Gold must implement a material testing process to determine longitudinal tensile and compressive strain capacity of pipe and girth welds, representing all anticipated operating and environmental conditions the pipeline will be subjected to during its life cycle. Based upon the findings from the material testing program and an engineering critical assessment, Donlin Gold must develop and implement written material, design, construction, and operations and maintenance specifications and procedures in accordance with the SBD Special Permit Conditions to prevent the strain demand for pipe and girth welds from exceeding the defined strain demand limits under operational conditions for the SBD segments. Devices or processes of strain demand monitoring must be installed or implemented during construction or operation (when locations of high strains are discovered after the pipeline is put in service), and Donlin Gold must report and remediate high strain conditions. The SBD Special Permit Conditions additionally specify quality control measures to ensure the reliability of girth welds, the requirements for a ROW construction monitoring program, operations and maintenance procedures, and reporting and certification procedures.

To protect the pipeline from corrosion, the SBD Special Permit Conditions file includes conditions for grounding and cathodic protection of SBD segments. The permit conditions specify that protection from interference current (e.g., from overhead electric transmission lines) and cathodic protection must be provided for all buried SBD segments within one year of installation of the pipeline in the ditch (including backfill) to meet 49 CFR 192.328(e) and 192.620(d)(5) through (8). During the commissioning of the cathodic protection systems and during the annual cathodic protection surveys, Donlin Gold must test for the presence of interference currents and areas with insufficient levels of cathodic protection that could materially impact pipe reliability. Should such conditions be detected, then Donlin Gold must take remedial action within one year of detection, whether through effective cathodic protection, additional grounding, or other technically viable means. The interference current protection and cathodic protection system may be temporary or permanent, but in all cases, one or more of the applicable criteria contained in Appendix D of Part 192 must be achieved and maintained. Both the interference protection and cathodic protection systems must include provisions for testing and monitoring the performance of the systems including provisions for measuring polarized pipe-to-soil potentials and alternating current coupons,[5] as a minimum.

The permit conditions require Donlin Gold to treat the SBD segments as though they are in HCAs and to therefore develop and implement an integrity management program (IMP) that meets the requirements of 49 CFR Part 192, Subpart O, except for the reporting requirements contained in 49 CFR 192.945. Donlin Gold would perform a baseline assessment that includes ILI assessment along the entire length of the SBD segments no later than pipeline

[5] Coupons are small pieces of metal used to monitor the level of cathodic protection on buried metal structures such as pipes.

commissioning. ILI must be repeated at intervals not to exceed seven calendar years, and Donlin must monitor the variance between ILI tool measurements and actual field conditions. Depending upon the severity of anomalies detected by ILI tools, Donlin must complete an evaluation or implement remediation measures that would include an immediate response, a response within one year, or a monitored response.

In addition, Donlin Gold's IMP would include a cathodic protection assessment of the SBD segments after pipe construction backfill and within nine months of placing the cathodic protection system in operation. Donlin Gold would also perform External Corrosion Direct Assessment in accordance with 49 CFR 192.925 on a maximum seven calendar year interval to evaluate and remediate external pipe coating and cathodic protection operational performance.

3.25.3.2.4 IMPACT REDUCING MEASURES FOR ALTERNATIVE 2

These effects determinations take into account impact reducing design features (Table 5.2-1 in Chapter 5, Impact Avoidance, Minimization, and Mitigation) proposed by Donlin Gold and also the Standard Permit Conditions and Best Management Practices (BMPs) (Section 5.3, Impact Avoidance, Minimization, and Mitigation) that would be implemented. Several examples of these are presented below, and many are discussed above in Section 3.25.3.2.2.

Design features most important for reducing impacts to pipeline reliability and safety include:

- Donlin would develop an Operations and Maintenance Plan/Manual; Health, Safety, and Environment Plan (including a Safety Plan/Program), Pipeline Surveillance and Monitoring Plan, and other plans that would outline safety measures that would be implemented during operations;
- The above-ground fault crossing of the pipeline was designed to resist surface fault rupture hazards, and would be designed to withstand the stress that could occur during a seismic event;
- Appropriate notices, warning signs, and flagging would be used to promote public safety, but barricades may also be used around dangerous areas such as open trenches during construction; and
- The project design includes locked security fencing surrounding pipeline aboveground facilities.

Standard Permit Conditions and BMPs most important for reducing impacts to pipeline reliability and safety include:

- Appropriate bonding/financial assurance;
- Verifying pipeline integrity with visual and other non-destructive inspections of welds, hydrostatic testing, use of in-line inspection tools, and aerial inspections, and
- Use of cathodic protection (specific method to be determined in final design) for corrosion protection of the steel pipeline.

3.25.3.2.5 ADDITIONAL MITIGATION AND MONITORING FOR ALTERNATIVE 2

While the Corps is considering additional mitigation to reduce the effects presented above (Tables 5.5-1 and 5.7-2 in Chapter 5, Impact Avoidance, Minimization, and Mitigation), no additional mitigation or monitoring measures have been identified to reduce effects to pipeline reliability and safety.

3.25.3.3 ALTERNATIVE 3A – REDUCED DIESEL BARGING: LNG-POWERED HAUL TRUCKS

The natural gas pipeline route and design approach would be the same under Alternative 3A as under Alternative 2. Under Alternative 3A, natural gas usage would increase from 11.2 BSCF/year to a peak of 15.5 BSCF/year. The natural gas pipeline proposed under Alternative 2 has an engineered capacity to accommodate 26 BSCF/year with additional compression (i.e., higher operating pressure) and would not require any modifications to the pipeline design to transport the increased amount. Therefore, the potential impacts on public health and safety from transportation of natural gas by pipeline would be identical to those impacts described for Alternative 2. The effects determinations take into account applicable impact reducing design features and BMPs, as discussed in Alternative 2. No additional mitigation or monitoring measures have been identified to reduce effects to pipeline safety and reliability.

3.25.3.4 ALTERNATIVE 3B – REDUCED DIESEL BARGING: DIESEL PIPELINE

The natural gas pipeline would not be constructed under Alternative 3B. Therefore, the potential impacts on public health and safety from transportation of natural gas by pipeline would not occur.

A leak or spill from a diesel pipeline would not be likely to cause an immediate impact to public safety because diesel is not likely to explode. Potential impacts to human health from diesel spills are discussed in Section 3.7, Water Quality; Section 3.22, Human Health; and Section 3.24, Spill Risk.

The effects determinations take into account applicable impact reducing design features and BMPs, as discussed in Alternative 2. No additional mitigation or monitoring measures have been identified to reduce effects to pipeline safety and reliability.

3.25.3.5 ALTERNATIVE 4 – BIRCH TREE CROSSING PORT

The natural gas pipeline route and design approach would be the same under Alternative 4 as under Alternative 2. Therefore, the potential impacts on public health and safety from transportation of natural gas by pipeline would be identical to those impacts described for Alternative 2. The effects determinations take into account applicable impact reducing design features and BMPs, as discussed in Alternative 2. No additional mitigation or monitoring measures have been identified to reduce effects to pipeline safety and reliability.

3.25.3.6 ALTERNATIVE 5A – DRY STACK TAILINGS

The natural gas pipeline route and design approach would be the same under Alternative 5A as under Alternative 2. Therefore, the potential impacts on public health and safety from transportation of natural gas by pipeline would be identical to those impacts described for Alternative 2. The effects determinations take into account applicable impact reducing design features and BMPs, as discussed in Alternative 2. No additional mitigation or monitoring measures have been identified to reduce effects to pipeline safety and reliability.

3.25.3.7 ALTERNATIVE 6A – MODIFIED NATURAL GAS PIPELINE ALIGNMENT: DALZELL GORGE ROUTE

The pipeline design approach would be the same under Alternative 6A as described for Alternative 2. The pipeline route would be the same for Alternative 6A as for Alternative 2, with the exception of a different alignment between MP 106.5 and MP 152.7 (see Chapter 2, Alternatives). However, the entire route variation is designated Class 1, as is the rest of the pipeline route, and Donlin Gold has not identified any HCAs along the route variation. Therefore, the potential impacts on public health and safety from transportation of natural gas by pipeline would be identical to those impacts described for Alternative 2. The effects determinations take into account applicable impact reducing design features and BMPs, as discussed in Alternative 2. No additional mitigation or monitoring measures have been identified to reduce effects to pipeline safety and reliability.

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